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PROJECT NO. 52373

REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN AND COMMENTS ON THE LSE OBLIGATION	**§ § §**	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

NEXTERA ENERGY RESOURCES, LLC'S COMMENTS IN PROJECT 52373

NextEra Energy Resources, LLC ("NextEra") appreciates the opportunity to participate in the Public Utility Commission of Texas's ("Commission") review of the Electric Reliability Council of Texas's ("ERCOT") wholesale electric market design and the related rule-making process.

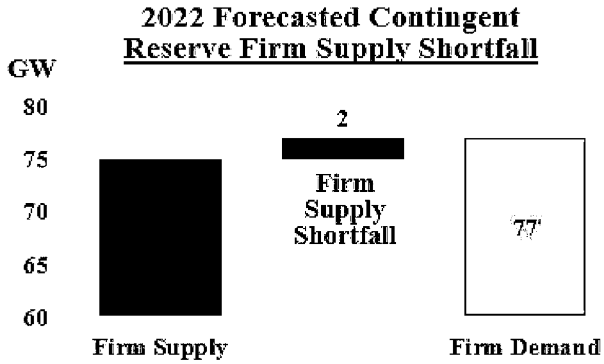
NextEra's Market Redesign Proposal

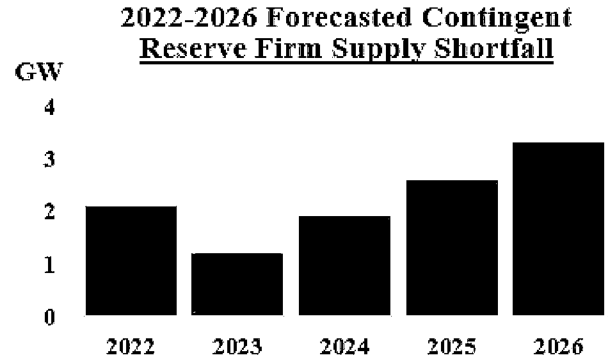
Over the past year, NextEra has evaluated various market redesign solutions ranging from traditional capacity constructs (similar to the LSE Obligation) to various ancillary products to improve reliability. Ultimately, NextEra proposed a new ancillary product, Contingent Reserve ("CRS"), which, coupled with ORDC reforms, utilizes ERCOT's energy-only framework to provide a low-cost solution that improves reliability. NextEra's solution can be implemented quickly by ERCOT, improve reliability in the near term, retain existing at-risk dispatchable generation, provide price signals to incentivize new generation, encourage market-driven and innovated solutions, all at a reasonable cost. Before addressing the Commission Staff's questions, NextEra respectfully summarizes the CRS product to emphasize the reliability benefits it could provide to ERCOT.

The CRS ancillary is intended to create a payment stream to the market's "marginal" generators. These are the resources that are not expected to operate under P50 generation and demand conditions but need to remain available to the market during more extreme supply and demand scenarios. These are also the generators that are most likely to retire based on their marginal economics but remain the most critical supply during tight market conditions. A payment stream to these generators via a CRS ancillary will ensure that these resources remain available to the market, and not retire. The CRS ancillary will achieve this objective through the following design structure:

1. **ERCOT will identify the annual volume needed for the CRS procurement.** The annual volume required for the CRS will be equal to any shortfall between projected firm peak demand and projected firm peak supply under P95 or other extreme conditions scenario. For the avoidance of doubt, the P95 or other extreme condition scenarios would factor in low wind and solar resource and high dispatchable and nuclear outages. The shortfall will continue

to evolve as demand response expands and new generation (including storage) grows to tighten the demand-supply shortfall.



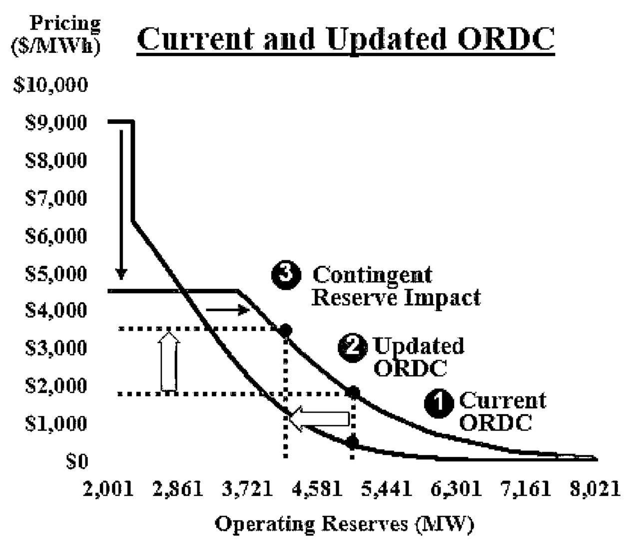


NextEra's proposed approach suggests 2-3 GW of CRS procurement, but ERCOT could stress the project firm demand and firm supply or include Commission-instructed reliability adders to alter the total amount of volume desired. Regardless, the outcome will result in an annual procurement need much lower than the LSE Obligation or other traditional capacity market constructs. As a result, the overall cost of CRS will be reasonable, and Texas can avoid paying all its generators for capacity that likely is not needed.

2. **ERCOT will procure portions of the CRS on a forward basis through multiple central auctions with the lowest cost clearing.**

ERCOT can utilize its existing auction framework to secure CRS. NextEra recommends facilitating a three-year auction process whereby 15% of the volume needed is procured three-years in advance, an additional 15% of the volume needed two-years in advance, and another 15% of the volume needed one-year in advance. ERCOT's final centralized auction, which would occur the season (calendar year, or some other annual time frame) before the volume is needed, would procure the remaining 55%. This illustration demonstrates the benefits of the CRS product. It is dynamic – the total volume needed can be altered by ERCOT as firm demand and firm supply changes over time, which can be reflected in each auction over the three-year period. It is transparent – all market participants will have visibility into clearing prices. It encourages competition – lowest costs wins. Finally, it addresses reliability – generators that run the least frequently (and therefore most likely to retire) will have the lowest lost opportunity cost from being withheld from the energy market and will have the lowest offer cost into the CRS auction. By winning the auction, these at-risk dispatchable generators will have a revenue stream that will prevent them from retiring and keep them in the ERCOT market.

3. **CRS is withheld from the energy market and utilized during scarcity events.**
When a scarcity event occurs, ERCOT would call on the generation that has been awarded a CRS obligation. In the event the generator does not respond, the generator would be required to return the CRS payment and be subject to a penalty for failing to perform. Importantly, withholding the CRS from the market will provide the secondary benefit of increasing spot energy prices. By reforming the ORDC and withholding the CRS from the market, this construct should result in higher prices with increased frequency. This will provide generators with greater security around cash flow streams, resulting in more economic clarity to maintain existing generation and encourage new investment. Specifically, CRS withholding coupled with an HCAP of $4,500, VOLL of $15,000, MCL of 2,300 MW, Mu of 883.56, and Sigma of 1912.67 will produce the desired support for existing and new generation.



NextEra appreciates the opportunity to summarize its CRS ancillary proposal and welcomes the opportunity to share additional details with the Commission.

<u>Response to Commission's Questions</u>

NextEra welcomes the opportunity to provide feedback on the LSE Obligation design. NextEra notes the following general observations:

- The LSE Obligation is a departure from the energy-only framework.

- The LSE Obligation has similar design features as a traditional capacity market whereby all qualified generators receive revenue even if they do not need additional revenue to remain in the market or are not called upon to perform.
- Although not currently valued, NextEra expects the LSE obligation will be costly and respectfully cautions the Commission to avoid adopting potential solutions that come without well-reasoned cost estimates.
- As recognized in the Commission staff's questions, the LSE Obligation, in its current form, introduces anti-competitive concerns related to market power and competitive retail choice. However, despite these concerns, NextEra recognizes the LSE Obligation will address reliability and therefore offers the following responses in an attempt to mitigate these risks.

1. ***The ORDC is currently a "blended curve" based on prior Commission action. Should the ORDC be separated into separate seasonal curves again? How would this change affect operational and financial outcomes?***

The ORDC should reflect the increasing risk of loss of load at lower reserve margin levels. It may be relevant to study how loss of load changes in different seasons between supply and demand dynamics; however, a historic analysis of loss of load probability will not reflect the current or future makeup of the supply stack and its inherent variability. We recommend maintaining the same ORDC parameters year-round.

2. ***What modifications could be made to existing ancillary services to better reflect seasonal variability?***

NextEra believes it would be appropriate for ERCOT to evaluate ancillary needs by season to reflect the differing supply and demand dynamics throughout the year. However, NextEra believes any modifications to existing ancillary services should attempt to limit any increase in costs, provide long-term visibility into procurement volume and be charged to load.

3. ***Should ERCOT develop a discrete fuel-specific reliability product for winter? If so, please describe the attributes of such a product, including procurement and verification processes.***

    - ***How long would it take to develop such a product?***
    - ***Could a similar fuel-based capability be captured by modifying existing ancillary services in the ERCOT market?***

During Winter Storm Uri, gas generation outages exceeded ERCOT's Seasonal Assessment of Resource Adequacy (SARA) estimate by approximately 19 GW. While these outages were caused by various drivers, the lack of secure fuel supply was a leading cause of the shortfall. Accordingly, NextEra believes ERCOT should require dispatchable generation to secure on-site fuel to improve reliability, especially during the winter. Since firming fuel through on-site fuel storage or other similarly secure fuel option requires significant investment, NextEra believes it is critical to provide generators with a cost-recovery mechanism through a new fuel-specific reliability product. NextEra believes the Commission could determine the appropriate fuel-secure volume and procure it through a competitive RFP, which would encourage market competition and reduce overall cost. Once the RFP is awarded, each generator would be responsible for securing the onsite fuel, such as constructing tanks, retrofitting equipment and filling tanks. The generators would then be reimbursed through the fuel-specific reliability product. NextEra believes the investment should either be recovered immediately, or the contract term for the service should be long enough to allow generation owners to use the revenue stream from the new product to finance the firm fuel costs and minimize the impact to customers by spreading the cost recovery over a longer period of time.

4. Are there alternatives to a load serving entity (LSE) Obligation that could be used to impose a firming requirement on all generation resources in ERCOT?

NextEra has significant concerns over the Commission's request for a firming "requirement". Investments in generation were made to provide non-firm supply. Any rule that seeks to retroactively require generators to provide firm supply re-trades prior investment decisions and is contrary to Texas' pro-business spirit. It would also undermine investor confidence for all generator types, add costs that increase the likelihood of additional generation retirements, and raises barriers for the development of new generation, all of which ultimately works against the Commission's objectives and leads to further erosion of reliability.

Given the Commission's concerns around reliability, NextEra believes it is critical that any market redesign solutions provide incentives to retain and encourage new investment in all generation types, as every megawatt hour is vital. NextEra strongly urges the Commission to focus on firming *incentives* – for example, providing higher levels of accreditation for renewables plus storage under capacity-type design proposals.

5. ***Are there alternatives to an LSE Obligation that could address the concerns raised about the stakeholder proposals submitted to the Commission?***

Per the introductory comments, NextEra believes its CRS ancillary plus ORDC reform proposal would better support ERCOT's needs while addressing the stated concerns.

Load Serving Entity (LSE) Obligation

6. ***How can an LSE Obligation be designed to protect against the abuse of market power in the wholesale and retail markets?***

The LSE Obligation design is similar to a capacity market without some of the principal benefits such as forward price transparency and the efficiencies that arise from a centrally cleared market. As designed, the LSE Obligation creates market power issues that will be difficult to mitigate and threaten to stifle ERCOT's vibrant retail choice marketplace, while exposing ratepayers to unnecessarily high costs. The principal challenges associated with the LSE Obligation include:

- Potential for Economic Withholding – Large generation owners (including the so-called "gentailers") may ask for above-market prices for their capacity, may refuse to deal with smaller retailers, or may prematurely retire their assets in order to artificially increase prices and earn excess wholesale profits. This could impose additional costs on independent retailers, potentially locking them out of the retail market or bankrupting them, which would further reduce retail competition.
- Predatory Retail Pricing – In a tight reserve margin environment in which capacity prices are high, a large generation-owner could sell capacity at below-market rates to their affiliated retailer to enable it to win more load and put competing retailers out of business. While the affiliated retailer will enjoy low capacity prices to pass through to customers, independent retailers will be forced to price contracts at the higher prevailing market prices, thus putting them at a disadvantage. The gentailer could then raise prices after its competitors have exited the market.
- Retail Load Forecast Uncertainty – In ERCOT's retail market, retailers face significant uncertainty as to what their future load will be, given that contracts typically are signed 6-12 months ahead and customer have significant flexibility to

switch between providers. As such, if the retailer over-forecasts even by a small amount the load to be procured, it will absorb significant costs due to the over-procurement, which could put it out of business. Under-forecasting can also put a retailer at a significant disadvantage if a lot of the capacity in the market has been contracted already. As such, an LSE Obligation construct significantly increases the risk for retailers in the ERCOT market and could force significant market concentration even if the market power issues could be effectively mitigated.

Market power mitigation is critical in contexts within which customer demand is inelastic, supply is concentrated, and there are significant barriers to entry. All of these apply, in varying degrees, to the ERCOT market and the proposed LSE Obligation construct. It will be critical that the Commission adopt strong market power mitigation measures in order to protect the competitive retail market. Options to help mitigate market power within an LSE Obligation include:

- Shift the compliance obligation from LSEs/REPs to Transmission / Distribution Service Providers (TDSPs), which could in turn charge all customers a non-bypassable charge based on the individual customer's 4 coincident peak (4CP). Under this construct, customers would face the same capacity pass-through cost regardless of which retailer is selected, helping to mitigate not only market power concerns but also retail load uncertainty. While customers can change retailers, they cannot change their load service territory and so would be served by the same TDSP regardless. Further, the TDSP would have the incentive to reduce the cost of the capacity obligation, given that customers would be able to at least partially avoid the cost by installing distributed generation, reducing the load being served through the TDSP. The large size of the TDSPs would also help them negotiate more effectively with large generation owners, helping lower costs.

- The Commission could establish stricter limits on LSE affiliated generation ownership to reduce market concentration. For example, the cap on power generation company (PGC) market share could be reduced to 15% or 10% in order to curb the potential exercise of market power.

- ***Will an LSE Obligation negatively impact customer choice for consumers in the competitive retail electric market in ERCOT? Can protective measures be put in place to avoid a negative impact on customer choice? If so, please specify what measures.***

  Yes, if the LSE Obligation is structured as a bilateral transaction market only and with insufficient or ineffective mitigation of market power, gentailers that control a significant amount of generation in ERCOT may artificially raise costs on independent retailers, effectively pricing them out of a retail market that is known for thin profit margins. This will be especially acute if reserve margins are low. Options to help mitigate market power within an LSE Obligation were answered in the previous question.

- ***How can market power be effectively monitored in a market where owners of power generation also own REPs that serve a large portion of ERCOT's retail customers?***

  Monitoring and mitigating market power is inherently challenging in a bilateral market in which generation ownership is concentrated among a few market participants, and a significant portion of the market is served by entities that have not opted into competition and operate using a vertically integrated utility model. NextEra believes a centrally administered and cleared auction model may help mitigate market power.

- ***What is the impact on self-supplying large industrial consumers who will have to comply with the LSE Obligation and will it impact their decision to site in Texas?***

  Any self-supplying end-use consumer should be indifferent to this proposal because their load obligation should be hedged by their generation ownership.

- ***What is the impact of an LSE Obligation on load-serving entities that do not offer retail choice, such as municipally owned utilities or electric cooperatives?***

  Municipally owned utilities and electric cooperatives that employ a vertically integrated utility model should be indifferent to an LSE Obligation. Any LSE that relies on the market to supply their Load Obligation would have additional market exposure.

- ***Can market power be monitored in the bilateral market if an LSE Obligation is implemented in ERCOT? Can protective measures be put in place to ensure that market power is effectively monitored in ERCOT with an LSE Obligation? If so, please specify what measures.*** See prior response.

- ***Should the LSE Obligation include a "must offer" provision? If so, how should it be structured?***

  NextEra believes a "must offer" obligation is necessary and can easily be implemented within the framework of a centrally administered and cleared market. In contrast, a must offer obligation would be administratively burdensome and difficult to enforce in a bilateral market, which is why NextEra favors a centrally market cleared design.

7. ***How should an LSE Obligation be accurately and fairly determined for each LSE? What is the appropriate segment of time for each obligation? (Months? Weeks? 24 hour operating day? 12 hour segments? Hourly?)***

An LSE's total obligation should be the sum of the individual customer obligations that the LSE serves at any point in time. The LSE obligation changes as customers switch providers, so it needs to be measured daily. The individual customer obligation, however, should be set for the period of one year based on the customer's load during the measurement period prior to the compliance year. Such measurement period could be the 4 CP intervals or a similar concept.

8. ***Can the reliability needs of the system be effectively determined with an LSE Obligation? How should objective standards around the value of the reliability-providing assets be set on an on-going basis?***

Yes, the reliability needs of the system can be determined by gathering sufficient data and performing appropriate studies, including a periodic Loss of Load Expectation (LOLE) study to understand the amount and type of capacity that is required. Renewable generation and storage should be accredited using industry-accepted methods such as Effective Load Carrying Capacity (ELCC) in order to ensure they are not over-credited in the construct.

- ***Are there methods of accreditation that can be implemented less administrative burden or need for oversight, while still allowing for all resources to be properly accredited?***

Yes. Similar to the PJM market, resources can self-designate a capacity accreditation but are charged penalties if the resource fails to deliver power during critical hours. This would result in the market setting generator accreditation in an efficient manner.

- ***How can winter weather standards be integrated into the accreditation system?***

In addition to allowing generation to self-designate their accreditation, generators that have gone beyond winter weather standards (for example, gas plants that procured on-site fuel or firm fuel supply) should receive a higher accreditation rating.

9. ***How can the LSE Obligation be designed to ensure demand response resources can participate fully and at all points in time?***

In order to allow demand response (DR) resources to reduce or avoid its contribution to the LSE obligation while at the same time maximize participation in other DR programs, market design features should consider the following:

- The customer-specific obligation for a period of time (*e.g.*, one year) should be set during a specific measurement period (*e.g.*, four CP). If DR resources curtail load during that measurement period, they would see a corresponding reduction in their customer specific obligation for the entire following year.

- There are limitations today on DR resources being able to participate in multiple DR programs at the same time. Those restrictions could be reviewed to determine whether more overlap is possible, including curtailment to manage the LSE Obligation.

10. ***How will an LSE Obligation incent investment in existing and new dispatchable generation?***

The capacity payments that existing and new generators will receive under the LSE Obligation construct will provide greater revenue certainty for generation-owners, making it easier to construct and finance new generation, as well as justify investment in the existing fleet. However, if the LSE Obligation is not designed with adequate consideration for generation outages and load forecast uncertainty – *i.e.*, procuring only 100% of the projected system peak load as outlined in Chairman Lake's memo, there may not be enough new generation entry to improve reliability beyond the level that is currently achieved by the energy-only market.

11. ***How will an LSE Obligation help ERCOT ensure operational reliability in the real-time market (e.g., during cold weather events or periods of time with higher than expected electricity demand and/or lower than expected generation output of all types)?***

An LSE Obligation could incentivize higher levels of real-time operational reliability through the following mechanisms:

- Capacity payments should provide greater revenue certainty for generators, which should result in more confidence in ongoing long-term operations, providing an incentive to invest in operational improvements.
- Strong performance incentives such as penalties for non-performance as well as bonuses payments paid out of penalties paid by under-performing resources.
- Higher capacity accreditation values for fuel-firming generators.

12. ***What mechanism will ensure those receiving revenue streams for the reliability services perform adequately?***

Previously addressed under Question 11.

13. ***What is the estimated market and consumer cost impact if an LSE obligation is implemented in ERCOT? Describe the methodology used to reach the dollar amount.***

NextEra has not estimated the cost of this proposal as it will depend greatly on the final design details.

14. ***How long will the LSE Obligation plan take to implement?***

NextEra defers to ERCOT to evaluate the time frame to implement.

15. ***If the Commission adopts an LSE Obligation, what assurances are necessary to ensure transparency and promote stability within retail and wholesale electric markets?***

See response to Question 6, above.

16. ***Are there relevant "lessons learned" from the implementation of an LSE Obligation in the SPP, CAL-ISO, MISO, and Australian markets that could be applied in ERCOT?***

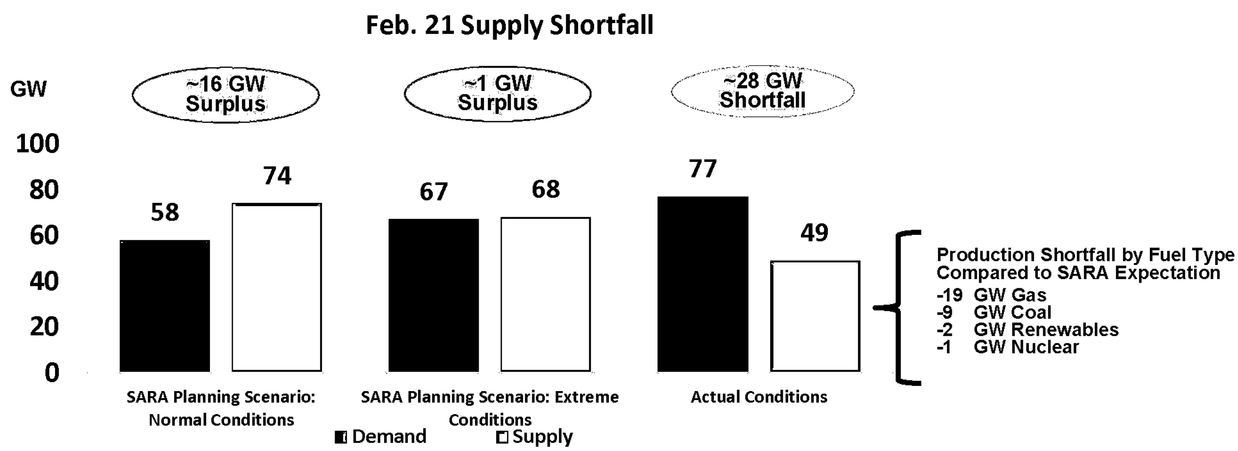
MISO: The Midcontinent ISO (MISO) imposes a Planning Reserve Margin Requirement (PRMR) on its LSEs based on the LSE's projected P50 MISO-coincident peak load (currently in the summer), and it enables the LSEs to meet the requirement either through self-supply or through a centrally organized Planning Resource Auction (PRA). The PRA is held two months before the start of the planning year, and while LSEs can contract bilaterally ahead of the PRA, there is no forward-looking price discovery. Further, MISO uses a vertical demand curve in the PRA, which results in volatile boom-bust cycles in capacity prices. The PRA has historically exhibited low capacity prices due to the market being long capacity in most years, a feature likely driven by the high participation of regulated investor-owned utilities (IOU) that are incentivized to build new capacity. MISO's high participation of regulated IOUs and very limited portion of the market with retail competition (*i.e.*, Illinois) stand in contrast to ERCOT. One key takeaway from the structure of MISO's PRA is to use a sloped rather than a vertical demand curve in order to promote more stable market outcomes and curb supply-side market power. Another key takeaway is to not schedule the auction too close to the compliance period unless there are other mechanisms to incent new generation entry; in the case of MISO, IOU participation drives new entry rather than the PRA itself.

SPP: Similar to MISO, the Southwest Power Pool (SPP) is a region with a significant presence of vertically integrated IOUs that have an incentive to procure new generation as needed. SPP currently has a Summer Season Resource Adequacy Requirement (RAR) that is enforced and a Winter Season Obligation that is not enforced. The Summer Season RAR requires each Load Responsible Entity (LRE) to procure enough capacity to cover its Net Peak Demand plus a Planning Reserve Margin, currently set at 12%. LREs can contract bilaterally to meet the obligation or own their own generation. There is no centralized auction, but any resource type can be used to meet the RAR, subject to capacity accreditation methods outlined by SPP. SPP has no retail market competition, however, and as such it does not suffer from some of the drawbacks outlined above for the LSE Obligation. There is no price transparency for SPP capacity prices and as such little true competition in its construct.

CAISO: The California Independent System Operator (CAISO) features a Resource Adequacy (RA) construct with some similarities to the LSE Obligation proposed for ERCOT. The primary lesson learned from the CAISO experience is a clear demonstration that a fully bilateral structure does not provide transparency to market prices. That is, the absence of a centralized auction and a lack of liquidity in the RA market makes it difficult for participants to determine the value of capacity and likely limits competitiveness and responsiveness to developing shortages. Given these shortcomings, CAISO has seen little to no competitive generation development, with almost all new supply relying on long-term contracts with LSEs or IOUs.

Cost Allocation to Renewables

NextEra believes ongoing attempts to justify allocating market redesign costs to renewables in the wake of Winter Storm Uri are misguided and removed from the reality of generator performance during February. When compared to ERCOT's SARA report, renewable production was generally in line with expectations, while natural gas generation and other dispatchable resources experienced outages at rates much higher than anticipated.



Appropriate non-discriminatory policy responses to the higher than anticipated outages by dispatchable generation include the Commission's weatherization requirements and the adoption of a fuel firming service previously discussed in response to the Commission's third question, not the assignment of market reform costs to renewables. Instead, the cost of market reforms, firm fuel services, and any other changes the Commission adopts to ensure reliability should fall to load, which is the ultimate beneficiary of efforts to improve reliability. NextEra reiterates its significant concerns that a decision to allocate costs to renewables will undoubtedly increase supply shortfalls, reduce reserve margins, and increase costs to consumers.

Renewable generation has lived up to its promise to provide low cost, intermittent green energy to the ERCOT market. NextEra estimates that ERCOT energy prices are $9/MWh lower due to renewable generation, and that this benefit will increase as new renewable generation is added to the system. Load is the exclusive beneficiary of low energy prices from renewable generation.

Under ERCOT's current ORDC construct, firm and dispatchable generation receives most of the compensation for reliable generation. Renewable generation generally is not compensated for reliability under the current ERCOT scarcity pricing construct.

ERCOT's current reliability shortfall results from the requirements of firm load. Shifting reliability costs away from load would allow load to continue to benefit from low cost renewable energy without bearing reliability costs resulting for firm load requirements. Any proposal to allocate load reliability costs to renewable generation that (i) provides load with low cost energy, (ii) was never intended to provide load with firm dispatchable power, and (iii) is not compensated for reliability is patently unfair.

1. Allocating costs to renewables will compound reliability challenges.

If reliability costs are allocated to renewables, NextEra projects ~10-17 GW of renewable generation will either retire or not be built over the next five years. As an intermittent resource, wind projects realize significantly lower revenues, and thus operate at tighter margins, making it impossible to absorb ancillary costs. Assigning ancillary costs to renewables will result in negative operating cash flows, prompting owners to shut down wind projects. If the ERCOT market loses 10-17 GW renewable generation over the next five years, NextEra projects power prices will increase by as much as ~$15/MWh, while at the same time fuel prices are on the rise and the ERCOT market needs every available megawatt of generation to meet load growth.

In addition to eroding reserve margins, reducing reliability, and increasing prices to consumers, changing the ERCOT market rules after the financial institutions who own renewable projects have invested billions of dollars discourages future investment in the Texas electric market, which in turn further stresses reliability and results in even higher prices for consumers.

2. Intermittent generation and dispatchable generation are different products.

Dispatchable generation realizes higher energy revenues than renewable generation as a result of its dispatchability and the ability of dispatchable generation to capture scarcity prices. The higher prices realized by dispatchable resources also results in higher prices for consumers, so customers pay a premium for energy from dispatchable resources. In contrast, renewable generation realize lower energy revenues because its intermittency only allows it to generate when the wind is blowing or sun is shining, which is typically when prices are lower.

It is discriminatory to charge renewables a reliability cost simply because they are, by design, not dispatchable, while at the same time not charging other non-dispatchable resources, like nuclear units, for their non-dispatchability. The efficient design of the energy-only market already penalizes renewables for their intermittency by providing lower energy revenues and not providing scarcity premiums when renewables are generating at high levels. Assigning additional costs to renewable generators because they are not dispatchable arbitrarily discriminates against certain forms of non-dispatchable generation.

3. Load is the sole party that benefits from reliability and thus should bear the cost consistent with cost-causation principles.

Lower prices realized by intermittent renewable resources result in lower prices for consumers, so customers receive a discount for energy from intermittent renewable resources. In addition, it is the reliability requirements of load that are driving the need for additional, more costly dispatchable generation on the ERCOT system. The reason additional reliability products are required is to reliably meet customer demand across a wide range of extreme weather conditions. The additional costs of meeting the reliability requirements of firm customers with inelastic demand during extreme weather events should be borne by those same customers. The cost causation created by firm load's reliability requirement is the reason why all ancillary services that are currently required to reliably operate the grid are borne by load. The fact that load's reliability requirements are the ultimate drivers of cost causation has not changed with the addition of renewables to the ERCOT gird, so the cost of all services required to providing reliable power should continue to be borne exclusively by load.

Load benefits from low-cost intermittent renewable generation and adding variable resources to the market does not increase the total cost of serving load. Load should not be able to benefit from the low-cost energy, low water consumption, and low emissions from renewables without also being encumbered by the marginal firming costs inherent in including renewables in the supply mix. If load takes the benefits but not the cost, then generation is subsidizing load.

Respectfully submitted

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ATTORNEYS FOR NEXTERA ENERGY RESOURCES

NEXTERA ENERGY RESOURCES EXECUTIVE SUMMARY OF COMMENTS ON MARKET DESIGN AND THE LSE OBLIGATION

Since Winter Storm Uri, NextEra has evaluated a number of market redesign solutions focused on improving reliability, ranging from traditional capacity markets to ancillary services. As many stakeholders have raised, the LSE Obligation design introduces anti-competitive concerns related to market power and competitive retail choice. NextEra shares these concerns. Texas values its energy-only market, competitive retail choice and price transparency; however, the LSE Obligation, in its current form, will hurt retailers and limit price discovery. Specifically, NextEra has the following concerns with the current LSE Obligation design:

- Economic Withholding: Generation owners with a large share market shares will have the ability drive up prices unless the LSE Obligation includes design elements that prevent the exercise of market power.
- Effects on Retail Competition: In a tight reserve margin environment, LSE affiliated generation owners ("gentailers") could favor affiliated LSEs and sell capacity at below-market prices, creating improper pricing advantages and driving competitive LSEs out of the market.
- Load Forecasting Risk: LSEs contract with load for contract terms of 12 months or less. If ERCOT over-forecasts an LSE's capacity obligation due to the longer-term forward LSE Obligation or customer migration after the LSE Obligation is assigned, the resulting LSE Obligation forecast error will create unmanageable risks and additional costs that LSEs will not be able to pass on to customers.

However, NextEra recognizes the Commission's goal of improving reliability and offers the following changes for the Commission's consideration, which could possibly help mitigate concerns:

- Market power and load forecast error concerns can be mitigated by shifting the compliance obligation from LSEs to Transmission and Distribution Service Providers (TDSPs), who can recover Load Obligation cost from all customers via a non-bypassable charge based on the individual customer's 4 coincident peak demand values (4CP).
- Market power concerns can be also mitigated by imposing stricter limits on LSE affiliated generation ownership to reduce market concentration and the potential for the exercise of market power.

The Commission requested alternatives to the LSE Obligation design and NextEra respectfully requests the Commission consider the previously presented Contingent Reserve ancillary. Contingent Reserve, which, coupled with ORDC reforms, utilizes ERCOT's energy-only framework to provide a low-cost solution. Contingent Reserves will improve reliability by using a centralized auction process to provide at-risk dispatchable generation with a revenue stream that will also send forward price signals to incentivize new generation. It is dynamic, it is transparent, it encourages competition, and it will immediately improve reliability. More details are shared in our comments.

Finally, since February, various stakeholders have raised or suggested that additional costs for market redesign should be borne by intermittent resources. NextEra reiterates its significant concerns over such a decision, which would undoubtedly increase supply shortfalls, reduce reserve margins and increase costs. NextEra respectfully submits the following facts around cost allocation:

- Allocating costs to renewables will compound reliability challenges. As an intermittent resource, renewable projects realize significantly lower revenues, and thus operate at tighter margins, making it impossible to absorb ancillary costs. If reliability costs are allocated to renewables, NextEra projects ~ 10-17 GW of renewable generation will either retire or not be built over the next five years, at a time when ERCOT needs every megawatt hour.
- Intermittent generation and dispatchable generation are different products. Renewables are paid lower revenues and do not capture scarcity pricing because they are, by design, intermittent. It is discriminatory to charge renewables a reliability cost because they are not dispatchable.
- Load is the sole party that benefits from reliability and thus should bear the cost consistent with cost-causation principles. The Commission is attempting to redesign its market and introduce new reliability products in attempt to meet customer demand. The additional cost created by firm load's reliability requirement should therefore be borne by load.

NextEra appreciates the opportunity to participate in the rule-making process and commends the Commission for their work thus far. Prior to finalizing any market redesign recommendation, NextEra strongly encourages the Commission to continue facilitating rigorous analysis across multiple market designs and to weigh all options carefully, including a thorough cost analysis.